TECHNICAL REVIEW DOCUMENT
For
RENEWAL / MODIFICATION TO OPERATING PERMIT 96OPMR171

Colorado Power Partners
Morgan County
Source ID 0870027

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November 2006 and January 2008
Revised March, September and October 2008

I. Purpose:

This document establishes the basis for decisions made regarding the applicable requirements, emission factors, monitoring plan and compliance status of emission units covered by the renewal and modification of the Operating Permit for the Colorado Power Partners facility. The current Operating Permit for this facility was issued on July 1, 2002 and expires on July 1, 2007. Prior to submittal of the renewal application, the source had submitted an application on March 27, 2006 to revise their Title V permit to set higher alternative BACT limits for startup and shutdown. Since this modification changes a case-by-case emission limitation, the modification must be processed as a significant modification as required by Colorado Regulation No. 3, Part C, Section I.A.7.c. A significant modification is processed under the same procedures as a renewal, i.e. it must go through a 30-day public comment period and EPA 45-day review period. Therefore, since the renewal application has been submitted the Division is incorporating the modification with the renewal.

This document is designed for reference during review of the proposed permit by EPA and for future reference by the Division to aid in any additional permit modifications at this facility. The conclusions made in this report are based on the source's request for a modification submitted on March 27, 2006, the renewal application submitted on June 19, 2006, additional information submitted on June 28, 2006 (to supplement the renewal application) and December 5, 2007, comments on the draft permit submitted on May 14, 2008, comments on the draft permit received October 10, 2008 via e-mail, previous inspection reports and various e-mail correspondence, as well as telephone conversations with the applicant. Please note that copies of the Technical Review Document for the original permit and any Technical Review Documents associated with subsequent modifications of the original Operating Permit may be found in the Division files as well as on the Division website at http://www.cdphe.state.co.us/ap/Titlev.html. This narrative is intended only as an adjunct for the reviewer and has no legal standing.

Any revisions made to the underlying construction permits associated with this facility made in conjunction with the processing of this operating permit application have been reviewed in accordance with the requirements of Regulation No. 3, Part B, Construction Permits, and have been found to meet all applicable substantive and procedural requirements. This operating permit incorporates and shall be considered to be a combined construction/operating permit for any such revision, and the permittee shall be allowed to operate under the revised conditions upon issuance of this operating permit without applying for a revision to this permit or for an additional or revised construction permit.

II. Description of Source

This facility consists of a cogeneration facility defined under Standard Industrial Classification 4911. Two combustion turbines, one of which is equipped with a heat recovery steam generator (HRSG) and duct burner, produce electricity for sale. The combustion turbines are equipped with enhanced water/steam injection pollution control systems to reduce NO_X emissions. One turbine is run in simple cycle mode (Brush 3) while the other is run in combined cycle mode (Brush 1). Each turbine serves a generator with a nameplate capacity of 28.5 MW. The waste heat from Brush 1 flows through a HRSG (equipped with a duct burner to provide additional heat) to generate steam, which is used to drive a steam turbine (30 MW) to generate additional electricity. The waste heat from the HRSG served by Brush 1 can also provide thermal energy to heat a local greenhouse complex. There are also two diesel-fired internal combustion engines that are used to start the turbines. There is also a cooling tower to cool water for the steam turbine. Note that the combustion turbines are referred to as Brush 1 or GT-1 (combined cycle) and Brush 3 or GT-2 (simple cycle).

Previously three natural gas fired auxiliary boilers were addressed in this permit. The auxiliary boilers were used to provide heat to the greenhouse when waste heat from the HRSG is not available or inadequate to meet the demand. However, in August 2007, the greenhouses and auxiliary boilers were bought by a third party and are addressed in a separate operating permit.

Based on the information available to the Division and provided by the applicant, it appears that no modifications to the significant emission units has occurred since the original issuance of the operating permit.

The facility is located in a 90 acre industrial area shared with the greenhouse and is just south of Brush. The area in which the plant operates is designated as attainment for all criteria pollutants.

There are no affected states within 50 miles of the plant and there are no Federal Class I designated areas within 100 kilometers of the plant.

The summary of emissions that was presented in the Technical Review Document (TRD) for the original permit issuance has been modified to more appropriately identify the potential to emit (PTE) since modifications have been made to the Colorado Power Partners (CPP) emission units, as well as the other emission units at the Brush Cogeneration Facility. Emissions (in tons/yr) at the facility are as follows:

Emission Unit	PM	PM_{10}	SO_2	NO_X	CO	VOC	HAPS
BCP – Turbine*	5.1	5.1	1.2	105.7	44	32	See Table on Page 18
BCP – Duct Burner							
BCP - Engine							
BCP – Cooling Tower	4.4	4.4					
BCP Total Emissions	**9.5**	**9.5**	**1.2**	**105.7**	**44**	**32**	**4.14**
CPP – Turbines*	5	5	3.4	134	147.5	24.2	See Table on Page 18
CPP – Duct Burners							
CPP – Engines							
CPP – Cooling Tower	2.5	2.5					
CPP Total Emissions	**7.5**	**7.5**	**3.4**	**134**	**147.5**	**24.2**	**8.02**
BIV – Turbines**	9.71	9.71	2.79	60	120	22.38	See Table on Page 18
BIV – Duct Burners							
BIV – Cooling Towers	6.87	6.87					
BIV Total Emissions	**16.58**	**16.58**	**2.79**	**50**	**120**	**22.38**	**6.12**
Brushco – Boilers				5	4.2		See Table on Page 18
Brushco – Boilers				11.5	9.7		
Brushco Total Emissions				**16.5**	**13.9**		**0.32**
Facility Total Emissions	**33.58**	**33.58**	**7.39**	**316.2**	**325.4**	**78.58**	**18.60**

*permitted emissions for the turbine(s), duct burner(s) and starter engine(s) is a combined limit.
**permitted emissions for the turbines and duct burners is a combined limit.

Potential to Emit is based on permitted emission limits. Based on APENs filed for 2005 data (APENs received on March 22, 2006), actual emissions from Brush 1 were 4.5 tons/yr of NO_X and 2.5 tons/yr of CO, all other criteria pollutant emissions were less than 1 ton and actual emissions from Brush 3 were less than 1 ton/yr for all criteria pollutants.

The breakdown of HAP emissions by emission unit and individual HAP is provided on page 18 of this document. Since the HAP emissions, on an hourly basis, are higher for the turbines than the duct burners, the HAP PTE is based on the turbines burning all the fuel (fuel consumption limits typically apply to the turbine(s) and duct burner(s) combined). For the BCP turbine, the turbine can run 8760 hrs/yr and there is leftover fuel for the duct burner to operate; therefore, HAP emissions for both the turbine and duct burner were calculated. HAP emissions for all equipment, except the turbines, are based on AP-42 emission factors. For the turbines, HAP emissions are based on the higher emission factor from either AP-42, California Air Toxic Emission Factors (CATEF) or EPA's August 22, 2003 memo on HAP emission factors for turbines.

MACT Requirements

Case-by-Case MACT - 112(j) (40 CFR Part 63 Subpart B §§ 63.50 thru 63.56)

Under the federal Clean Air Act (the Act), EPA is charged with promulgating maximum achievable control technology (MACT) standards for major sources of hazardous air pollutants (HAPs) in various source categories by certain dates. Section 112(j) of the Act requires that permitting authorities develop a case-by-case MACT for any major sources of HAPs in source categories for which EPA failed to promulgate a MACT standard by May 15, 2002. These provisions are commonly referred to as the "MACT hammer".

Owner or operators that could reasonably determine that they are a major source of HAPs which includes one or more stationary sources included in the source category or subcategory for which the EPA failed to promulgate a MACT standard by the section 112(j) deadline were required to submit a Part 1 application to revise the operating permit by May 15, 2002. The source submitted a notification but the cover letter for the notification indicated that they did not believe that HAP emissions from the facility were above the major source level (10 tons per year of any single HAP or greater than 25 tons per year of all HAPs combined), but requested that the Division indicate whether the source is major for HAPS. Based on the Division's analysis, the Brush Cogeneration Facility is a major source of HAPS for a covered source category (combustion turbine, reciprocating internal combustion engines (RICE) and industrial, commercial and institutional boilers and process heaters). Since the EPA has signed off on final rules for all of the source categories which were not promulgated by the deadline, the case-by-case MACT provisions in 112(j) no longer apply. Note that there is a possible exception to this, as discussed later in this document (see under industrial, commercial and institutional boiler and process heaters).

Combustion Turbine MACT (40 CFR Part 63 Subpart YYYY)

In accordance with 40 CFR Part 63 Subpart YYYY §63.6090(b)(4), existing (construction commenced prior to January 14, 2003) stationary combustion turbines do not have to meet the requirements of Subparts A and YYYY, including the initial notification requirements.

RICE MACT (40 CFR Part 63 Subpart ZZZZ)

The RICE MACT (40 CFR Part 63 Subpart ZZZZ) was signed as final on February 26, 2004 and was published in the Federal Register on June 15, 2004. An affected source under the RICE MACT is any existing, new or reconstructed stationary RICE with a site-rating of more than 500 hp. In accordance with 40 CFR Part 63 Subpart ZZZZ § 63.6590(b)(3), existing (commenced construction or reconstruction prior to December 19, 2002) compression ignition engines do not have to meet the requirements of Subparts A and ZZZZ, including the initial notification requirements. The two diesel-fired starter engines have a site horsepower of more than 500 hp and commenced construction prior to December 19, 2002; therefore, the RICE MACT requirements do not apply to these engines.

However, revisions were made to the RICE MACT to address engines ≤ 500 hp and engines at area sources. These revisions were published in the federal register on January 18, 2008. Under these revisions, existing 4SRB, 2SLB, 4SLB and CI engines are exempt from the requirements. For purposes of the MACT, for engines ≤ 500 hp, "existing" means commenced construction or reconstruction before June 12, 2006. There are engines addressed in the insignificant activity list (portable power generator and portable welding unit); however, these engines commenced construction prior to June 12, 2006 and as a result the requirements in the RICE MACT requirements do not apply to these engines.

Industrial, Commercial and Institutional Boilers and Process Heaters MACT (40 CFR Part 63 Subpart DDDDD)

The final rule for industrial, commercial and institutional boilers and process heaters was signed on February 26, 2004 and was published in the Federal Register on September 13, 2004. There are process heaters included in the insignificant activity list in Appendix A of the permit. Although 40 CFR Part 63 Subpart DDDDD applies, existing (constructed before January 13, 2003) small gaseous fired units are not subject to any of the requirements in 40 CFR Part 63 Subparts A and DDDDD, including the initial notification requirements (§ 63.7506(c)(3)). The process heaters at this facility that are listed in the insignificant activity list would fall under the existing small gaseous fired unit category and would therefore not be subject to any requirements.

In addition, there is a duct burner associated with one of the combustion turbines that is considered a significant emission unit. In accordance with the provision in 40 CFR Part 63 Subpart DDDDD § 63.7491(c), the provisions in Subpart DDDDD do not apply to electric utility steam generating units (EUSGU), which is a fossil fuel-fired combustion unit of more than 25 MW that serves a generator that produces electricity for sale. A fossil fuel-fired unit that cogenerates steam and electricity, and supplies more than one-third of its potential electric output capacity and more than 25 MW electrical output to any utility power distribution system for sale is considered an electric utility steam generating unit.

Brush 3, which consists of a turbine and duct burner operated at one time as a cogeneration unit and never sold (on an annual basis) more than one third of its potential electrical output capacity and more than 25 MW, however, it no longer operates as a cogeneration unit. 40 CFR Part 63 Subpart DDDDD does not include a definition of a cogeneration unit; therefore it is not clear whether units that operated as a cogeneration unit at one time would still be considered a cogeneration unit if they still have the equipment for cogeneration but no longer use it. Under the provisions of 40 CFR Part 60 Subpart Da (Standards of Performance for Electric Utility Steam Generating Units for which Construction Commenced after September 18, 1978), a cogeneration unit is defined as a "steam generating unit that simultaneously produces both electric (or mechanical) and useful thermal energy from the same primary energy source. Therefore, since the unit is no longer operated as a cogeneration unit and since the unit serves a generator that is over 25 MW, the Division considers that this unit does qualify as an EUSGU and is therefore, not subject to the requirements in 40 CFR Part 63 Subpart DDDDD.

As of July 30, 2007, the Boiler MACT was vacated; therefore, the provisions in 40 CFR Part 63 Subpart DDDDD are no longer in effect and enforceable. The vacatur of the Boiler MACT triggers the case-by-case MACT requirements in 112(j), referred to as the MACT hammer, since EPA failed to promulgate requirements for the industrial, commercial and institutional boilers and process heaters by the deadline. Under the 112(j) requirements (codified in 40 CFR Part 63 Subpart B §§ 63.50 through 63.56) sources are required to submit a 112(j) application by the specified deadline. As of this date, EPA has not set a deadline for submittal of 112(j) applications to address the vacatur of the Boiler MACT. It is not clear whether 112(j) applications would be required for the small process heaters that were affected sources under the Boiler MACT but were not subject to any requirements. Nor is it clear whether 112(j) applications would be required for emission units, such as EUSGUs, which were excluded from the Boiler MACT but are considered affected facilities under the NSPS for industrial-commercial-institutional steam generators. Therefore, the Division has not included a requirement in the permit to submit a 112(j) application. If the Division considers that in the future, a 112(j) application will be required for small units and EUSGUs the source will be notified.

CAM Requirements

Although the turbines are equipped with steam injection to reduce NO_X emissions, since the Title V permit specified a continuous monitoring method for NO_X the turbines are not subject to the CAM requirements as allowed by 40 CFR Part 64 § 64.2(b)(vi).

In addition, although the cooling water tower is equipped with drift eliminators, drift eliminators are not considered control devices as defined in 40 CFR Part 64 § 64.1, as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV, since the drift eliminators act as a passive control measure to prevent the release of pollutants (i.e. drift).

Acid Rain Requirements

In preparing the original Title V permit for this facility, the Division requested that the source provide information regarding the applicability of the Acid Rain program to Brush 1 (Brush 3 is subject to the Acid Rain requirements, therefore, additional information on applicability was not requested for that unit). The Division reviewed the information submitted and agreed with the source's position that the Acid Rain requirements did not apply to Brush 1. However, the Division is reviewing the Acid Rain applicability again at this time, since we are aware that some minor errors were made in our original analysis.

As part of the processing of the original Title V permit, the source submitted information indicating that Brush 1 met the definition of a cogeneration unit under 40 CFR Part 72 and that based on permit limits the unit could not supply more than 219,000 MWe-hr electricity in any year. Therefore, the source concluded that Brush 1 was not subject to the Acid Rain requirements because Brush 1 was a cogeneration unit that could not sell more than 219,000 MWe-hr. The source also noted that they had entered into a power purchase agreement prior to November 15, 1990.

In processing the original Title V permit, the Division reviewed the information submitted by the source and conducted our own analysis, since there were errors in the source's submittal and summarized our conclusions in the technical review document for the original permit. The Division's analysis was flawed in that the potential electrical output capacity for Brush 1 was calculated incorrectly. Therefore, the Division is reviewing the Acid Rain applicability of Brush 1 again with the renewal permit.

As discussed above in this document under "MACT Requirements – Industrial, Commercial and Institutional Boilers and Process Heaters MACT (40 CFR Part 63 Subpart DDDDD)", the Division considered that Brush 1 was an EUSGU since the unit no longer operated as a cogeneration unit. However, under the Acid Rain Permits Regulation (40 CFR Part 72) a cogeneration unit is defined as a "a unit that has equipment used to produce electric energy and forms of useful thermal energy (such as heat or steam) for industrial, commercial, heating or cooling purposes, through sequential use of energy". Unlike the definition of cogeneration unit in 40 CFR Part 60 Subpart Da, under the Acid Rain Program a unit that operated as a cogeneration unit at one time, is still considered a cogeneration unit provided the cogeneration equipment is still in place. The Division confirmed that although Brush 1 is not operating as a cogeneration unit, it still has the equipment to operate as one; therefore, under the Acid Rain Program Brush 1 is still a cogeneration unit. A cogeneration unit is exempt from the Acid Rain Program provided that in any three calendar year period, the unit does not sell an annual average of more than one-third of its potential electrical output capacity and more than 219,000 MWe-hrs actual electric output.

The Division determined that the potential electric output capacity of Brush 1 is 58.6 MWe (calculated in accordance with the requirements in 40 CFR Part 72 Appendix D) and one-third of the unit's potential electrical output capacity is 171,110 MWe-hr, on an annual basis. Based on the permitted fuel consumption limits for the facility and assuming a natural gas heat content of 1020 Btu/scf, Brush 1 can operate for approximately 3,808 hours in any year, which results in annual power sales of 223,150 Mwe-hr, which exceeds the 219,000 Mwe-hr threshold for the Acid Rain Program exemption. Therefore, as long as in any three calendar year period, Brush 1 sold no more than an annual average of 219,000 Mwe-hrs, the unit is exempt from the Acid Rain Program. The source provided the Division with power sales data for this unit for 1991 through 2007, which indicated that the annual power sales for each calendar year period was less than 219,000 Mwe-hr.

Note that as discussed in the technical review document for the original Title V permit, since the source entered into a power purchase agreement prior to November 15, 1990, Brush 1 may also be exempt from the Acid Rain Program under 40 CFR Part 72 § 72.6(b)(6) (independent power production facilities exemption).

III. Discussion of Modifications Made

Source Requested Modifications

The source submitted an application to modify their permit on March 27, 2006. In addition, the source submitted a renewal application on June 19, 2006 with additional information submitted on June 28, 2006 to complete the renewal application. In their renewal application, the source indicated that they were requesting the changes identified in their March 27, 2006 modification application.

The source's requested modifications identified in the modification request and the renewal application were addressed as follows:

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In their March 27, 2006 modification request, the source indicated new addresses and contact information for the permit contact and the responsible official. The permit was revised to reflect the responsible official's new title and phone number and to reflect the permit contact's new phone number.

In their comments on the draft permit received on May 14, 2008, the source requested that the Responsible Official be changed. This change has been made as requested.

NSPS Subpart Db NO_X Limit Compliance

In their March 27, 2006 modification application, which is referenced in their renewal application, the source requested that the permit be revised to specify that compliance with the NSPS Subpart Db NO_X limit (applies to the Brush 1 duct burner) would be demonstrated with an annual performance test rather than with the NO_X continuous emission monitoring system (CEMS). The Division considers that it is not appropriate to specify that compliance with a NO_X limit be monitored through an annual performance test when the emission unit is equipped with a NO_X CEMS. Nevertheless the Division believes that the NSPS Db limit may be less stringent than the NO_X BACT limits for

Brush 1 and if that is the case then the NSPS Db NO_X limit can be streamlined out of the permit in favor of the NO_X BACT limit.

The NSPS Db NO_X limit is 0.20 lb/mmBtu, on a 30-day rolling average. As specified in 40 CFR Part 60 Subpart Db § 60.44b(h), the NO_X limit applies during periods of startup, shutdown and malfunction. The NO_X BACT limits for Brush 1 are 33, 40 (startup) and 60 (shutdown), all are in units of ppmvd at 15% O_2 and on a 1-hour average. The NO_X BACT emission limitations must be converted to the same units as the NSPS Db limit for comparison. Using EPA Method 19, Equation 19-1, the NO_X BACT limits were converted to units of lb/mmBtu, with the following results 33 ppmvd (0.1216 lb/mmBtu), 40 ppmvd (0.1474 lb/mmBtu) and 60 ppmvd (0.2210 lb/mmBtu). All but the shutdown NO_X limit are more stringent than the NSPS Db NO_X limit. When the startup and shutdown BACT limits are averaged together, the result is 0.1842 lb/mmBtu, which is more stringent than the NSPS Db limit. Since there would not be a shutdown hour without a startup hour (and some hours at the lower BACT limit of 0.1216 lb/mmBtu) and because the BACT limits are on a 1-hr average versus the 30-day rolling average for the NSPS Db limit, the Division considers that the NO_X BACT limits are more stringent than the NSPS Db NO_X limit. Therefore, the Division will streamline out the NSPS Db NO_X limit in favor of the NO_X BACT limits.

Note that NSPS Db specifies that for duct burners compliance with the NSPS limits may be demonstrated with a performance test, rather than a NO_X CEMS. NSPS Db specifically states that duct burners are not required to have NO_X CEMS (40 CFR Part 60 Subpart Db § 60.48b(h)). Since the source has demonstrated compliance with the NSPS Db NO_X limit with a performance test, the NSPS Db NO_X CEMS requirements do not apply to the duct burner and therefore need not be considered further for purposes of streamlining.

<u>Data Acquisition and Handling System (DAHS) Hourly Data Validation</u>

The source requested in their March 27, 2006 application, which is referenced in their renewal application, that the permit be revised to specify that hours shall be validated in accordance with the provisions in 40 CFR Part 75 § 75.10(d), as required by a Compliance Order on Consent (2004-033, signed June 16, 2005) issued for this facility by the Division. The source suggested that language be added to Section II, Conditions 1.4.1 and 1.5.1 to address the valid hour definition. However, the Division considers that this language would be more appropriate to include these requirements in the permit with the CEMS requirements (Section II.4). The Division has included language in the permit in Section II.4 indicating that valid hours shall be determined in accordance with the requirements in § 75.10(d).

<u>DAHS/CEMS Data Quality Assurance/Quality Control (QA/QC)</u>

In their March 27, 2006 application, which is referenced in the renewal application, the source included a discussion regarding the specific QA/QC requirements for the CEMS. Typically the Division has not been overly specific on the CEMS and have typically just indicated that the CEMS shall meet either the requirements of 40 CFR Part 60 or Part 75. In this case, the Division will include some more specific requirements for the CEMS at this facility. Therefore, the CEMS requirements have been revised to address some of the more specific provisions noted in the source's application. These revisions have been made to Section II.4 (CEMS requirements).

In addition, in their comments on the draft permit (received on May 14, 2008), the source requested that language be added indicating that the file format required by Section II, Condition 4.2.5 be either hardcopy, electronic or combination.

Startup/Shutdown BACT Limits

In their March 27, 2006 application, which is referenced in the renewal application, the source requested a revision to their startup and shutdown BACT limits. The current permit includes startup and shutdown BACT limits in units of ppmvd and the source is requesting that a lbs/hr limit be added to the current limit. Under the source's proposed startup and shutdown BACT limit, if the source were out of compliance with the ppmvd limit, the mass emission rate (lbs/hr) for that hour would be compared to the proposed new lbs/hr BACT limit to determine if the unit is out of compliance. In order to be out of compliance, the unit would have to exceed both the ppmvd limit and the proposed new lbs/hr limit. This type of dual startup/shutdown BACT limit has been used for the Ft. St. Vrain turbines. The Division has agreed to include an additional lb/hr limit to the startup and shutdown BACT limits for the units at this facility.

The source requested the lb/hr startup and shutdown limits based on the ppmvd limits for the units, converted to lb/mmBtu based on Method 19, Equation 19-1) and the maximum heat input rate for the unit. The requested lbs/hr limit are shown in the table below:

Brush 1 (turbine plus duct burner)			Brush 3 (turbine)		
Existing Limit	Unit Heat Input Rate (mmBtu/hr)	Requested Limit (lbs/hr)	Existing Limit	Unit Heat Input Rate (mmBtu/hr)	Requested Limit (lbs/hr)
NO_X S/U 40 ppmvd @15% O_2 (0.1474 lb/mmBtu)	600	88.4	NO_X S/U 40 ppmvd @15% O_2 (0.1474 lb/mmBtu)	420	61.9
NO_X S/D 60 ppmvd @ 15% O_2 (0.2210 lb/mmBtu)	600	132.6	NO_X S/D 60 ppmvd @ 15% O_2 (0.2210 lb/mmBtu)	420	92.8
CO S/U & S/D 200 ppmvd @ 15% O_2 (0.4482 lb/mmBtu)	600	268.9	CO S/U & S/D 200 ppmvd @ 15% O_2 (0.4482 lb/mmBtu)	420	188.2

The source's proposed lb/hr emission limits are based on the maximum heat input rate of the unit; however, the unit may not be at full load during startup and/or shutdown; therefore, the Division does not necessarily agree with the source's method for setting a lb/hr BACT emission limit. The Division prefers to base this number on actual emission data during startup and shutdown periods.

The source did not submit any startup and shutdown emission data with their March 27, 2006 application and the quarterly excess emission reports only provide emission data in units of ppmvd, not lbs/hr. However, startup and shutdown emission data was submitted in October 2000 to support the addition of startup and shutdown BACT limits in the original Title V permit for this facility. That data included emission data in ppmvd, as well as in lbs/hr. A review of that emission data indicates the highest NO_X lbs/hr emission rate at 94.5 lbs/hr and the highest CO emission rate at 253.6 lbs/hr. Based on the highest lb/hr emission rates from each of the 31 startups and shutdowns in the October 2000 submittal, only 1 exceeded 90 lbs/hr for NO_X and 7 exceeded 200 lbs/hr for CO (the average value of those 7 was 223 lbs/hr). Therefore, the Division initially set the lbs/hr limit for NO_X at 90 lbs/hr and CO at 223 lbs/hr. However, in their comments submitted during the public comment period, the source requested that the Division set the startup and shutdown BACT lb/hr limits at the initially requested level. Although the Division does not agree with the method used to set the limits, we agreed to set the limits at the requested values for those cases where the limits were supported by data submitted in 2000. For the two situations not supported by actual data (Brush 1 CO limit and Brush 1 NO_X shutdown limit), the lbs/hr BACT limits were set at the highest values in the 2000 data.

The request to revise the startup and shutdown BACT limits will result in an increase in the short-term emission rates during certain operating conditions, which are typically short in duration. Based on past modeling analyses conducted for this facility, these increases are not expected to cause or contribute to a violation of the national ambient air quality standards (NAAQS) or the Colorado ambient air quality standards (CAAQS). In addition, these increases are not expected to have a significant affect on air quality related values (AQRVs). Therefore, revised modeling is not warranted for the revised startup and shutdown BACT limits.

<u>CEMS Requirements (Section II, Condition 1.7)</u>

In their May 14, 2008 comments on the draft permit, the source requested some minor revisions to the CEMS requirements in Condition 1.7. The source requested that the permit be revised to specify that the concentration of NO_X and CO were measured in ppmvd at 15% O_2. In addition, the source requested that the Division add language indicating that the moisture content of the exhaust and the exhaust gas flow rate could be parametrically monitored. The Division revised the permit as requested.

<u>Insignificant Activity List (Appendix A)</u>

In their May 14, 2008 comments on the draft permit, the source submitted a revised insignificant activity list. This list has been included in the permit.

<u>Other Modifications</u>

In addition to the source requested modifications, the Division has included changes to make the permit more consistent with recently issued permits, include comments made by EPA on other Operating Permits, as well as correct errors or omissions identified during inspections and/or discrepancies identified during review of this renewal.

The Division has made the following revisions, based on recent internal permit processing decisions and EPA comments to the Colorado Power Partners Renewal Operating Permit. These changes are as follows:

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- Monitoring and compliance periods and report and certification due dates are shown as examples. The appropriate monitoring and compliance periods and report and certification due dates will be filled in after permit issuance and will be based on permit issuance date. Note that the source may request to keep the same monitoring and compliance periods and report and certification due dates as were provided in the original permit. However, it should be noted that with this option, depending on the permit issuance date, the first monitoring period and compliance period may be short (i.e. less than 6 months and less than 1 year).

General

- The Reg 3 citations were revised throughout the permit, as necessary, based on the recent revisions made to Reg 3.

Section I – General Activities and Summary

- Revised the description under Condition 1.1 to indicate that Brush 1 is operated in combined cycle only.

- In addition, Condition 1.1 was revised to reflect that the boilers are owned by a separate company and are addressed in a separate Title V permit. A request was submitted on November 17, 2007 to transfer ownership of the boilers at the Brush Cogeneration Facility to a separate owner.

- Revised the language in Condition 1.4 to reflect that only the last paragraph of Section V, Condition 3.g is state-only.

- Removed Section II, Condition 2.7 (opacity) from Condition 1.4 as a state-only requirement, since this applied to the boilers, which are no longer addressed in this permit.

- In addition, Section V, condition 3.d was added as a state only condition in Condition 1.4. Note that Section V, Condition 3.d (affirmative defense provisions for excess emissions during malfunctions) is state-only until approved by EPA in the SIP.

- Made minor revisions to the language in Condition 3.1 to be more consistent with other permits. In addition, added the operating permit issued for the boilers at the Brush Cogeneration Facility (Brushco Farms, 07OPMR299) to the list in Condition 3.2.

- The following changes were made to the Table in Condition 5.1.

  - Added a column to the Table in Condition 5.1 for the startup date of the equipment.
  - Removed the boilers from the table.
  - Added the serial number for the starter engines and indicated the size of these units (600 hp).
  - Included separate lines in the table for Brush 1, Brush 3 and the starter engines.
  - Removed the column labeled “Emission Unit Number”.
  - Under the column labeled “Facility Identifier” replace “S001” and “S002” with “GT-1” and “GT-2”

- Based on information requested by the Division and provided by the source in a November 13, 2006 e-mail, the starter engine serial numbers were included in the Table in Condition 5.1.

- Added a “new” Condition 5 for compliance assurance monitoring (CAM) requirements. Note that no emission units are subject to the CAM requirements.

<u>Section II.1 – Turbines, Engines and Duct Burner</u>

- Revisions were made to the permit to indicate that Brush 1 is operated in combined cycle only and that Brush 3 is operated in simple cycle only. These revisions included replacing “simple cycle” in the table with “Brush 3” and “combined cycle” cycle in the table with “Brush 1”. In addition, a note was added to the permit condition for the Reg 1 PM limit indicating that the PM limit would be lower for Brush 3, if no fuel is fired in the duct burner.

- Revised the equations in Condition 1.2.1 to calculate emissions in units of “tons/month” rather than “lbs/month”.

- Revised the SO_2 emission factors listed in Condition 1.2.1 for Brush 1 (turbine and duct burner) to the default emission factors in 40 CFR Part 75 Appendix D for units burning pipeline quality natural gas.

- Removed Condition 1.10 (determine Btu content of gas). In their comments on the draft permit, the source requested that they be allowed to determine the Btu content of the gas in accordance with 40 CFR Part 75. In lieu of including several options for determining the heat content, the Division added language to Condition 1.2.1 and 1.3.1 (calculating PM, PM_{10}, VOC and SO_2 emissions) requiring the source to use the heat input determined from the data acquisition and handling system (DAHS) from the continuous emission monitoring systems to calculate emissions.

- Removed the note in Condition 1.12 regarding periods of shutdown and offline emissions.

- Removed the requirement from Condition 1.15 to submit a copy of the annual certification to the Division. As a result of revisions to the Acid Rain Program made with the Clean Air Interstate Rule (final published in the federal register on May 12, 2005), annual compliance certifications are no longer required, beginning in 2006. The annual certification required for the Title V permit will serve as the compliance indicator for the Acid Rain provisions of the permit.

- Based on EPA's response to a petition on another Title V operating permit, minor language changes were made to various permit conditions (both in the table and the text) to clarify that only natural gas and/or diesel is used as fuel for permit conditions that rely on fuel restriction for the compliance demonstration.

- Revisions were made to the requirements in NSPS Subpart GG (published in the federal register on July 8, 2004). These revisions provided additional monitoring options for NO_X emissions and nitrogen and sulfur content of fuel that have been previously approved by EPA as alternative monitoring. The revised NSPS allows sources to use a NO_X CEMS in lieu of monitoring the water to fuel ratio, does not require monitoring of the nitrogen content of the fuel if the source has not taken credit for fuel-bound nitrogen in their NO_X emission limit and does not require that fuel be sampled for the sulfur content if natural gas is used as fuel. In general, most of the NSPS GG monitoring requirements had been streamlined from the permit (in Section IV.3) since other requirements were considered more stringent. No changes to the permit are necessary in Section II.1. Note that other changes will be made to the permit shield for streamlined conditions (Section IV.3) of the permit.

<u>Section II.2 – Boilers</u>

- Removed these requirements since the boilers are now addressed in permit 07OPMR299.

<u>Section II.3 – Cooling Water Tower</u>

- Revised the opacity language in Condition 3.4 to more closely match the language in Reg 1.

- Based on comments on the draft permit submitted by the source on May 14, 2008. the reference to "hours of operation" in the equation in Condition 3.2 was changed to "pump run time".

<u>Section II.4 – Continuous Emission Monitoring Requirements</u>

- Removed the language related to opacity in Condition 4.2.1, since the unit is not subject to any opacity requirements in 40 CFR Part 60.

- Removed the language related to either the continuous opacity monitoring systems (COMS) or opacity in Condition 4.2.2, since natural gas fired units are not required to installed continuous opacity monitoring systems (per 40 CFR Part 75 § 75.14(c)). Since the language regarding the COMS was removed the note specifying that the COMS did not apply was also removed.

- Condition 4.3 (data replacement requirements) was removed from the permit. The Division's Field Service's Unit considers that this requirement is not necessary; therefore it has been removed from the permit. Note that the source is still required to follow the monitoring requirements in 40 CFR Part 75 for purposes of the Acid Rain program (Section III of the permit) and as such are required to replace data as specified in 40 CFR Part 75 for purposes of reporting emission data for that program.

<u>Section III – Acid Rain Requirements</u>

- Revise the information on the designated representative (DR) and alternate designated representative (ADR).

- Moved the language specifying changes to the DR and ADR from Section 4 to Section 1 (directly under the DR and ADR). In addition, removed the language in this paragraph requiring the source to submit a copy of any revised certificate of representation to the Division. Submitting a copy of the certificate of representation to the permitting authority is not required under the regulations.

- Revised the table to include calendar years corresponding to the relevant permit term for the renewal.

- Minor changes were made to the standard requirements, based on changes made to 40 CFR Part 72 § 72.9.

- Removed the requirement to submit the annual compliance certification in Section 4 (Reporting Requirements). As a result of revisions to the Acid Rain Program made with the Clean Air Interstate Rule (final published in the federal register on May 12, 2005), annual compliance certifications are no longer required, beginning in 2006.

<u>Section IV – Permit Shield</u>

- Revised the citation to reflect revisions and restructuring of Reg 3 and remove Reg 3, Part C, Section V.C.1.b and C.R.S. § 25-7-111(2)(I) since they don't address the permit shield.

- In Section 3 (Streamlined Conditions) the following changes were made:

- References to Section II, Conditions 4.1, 4.2 and 4.4 were revised to 3.1, 3.2 and 3.4. Renumbering occurred due to the removal of the boilers.
- Corrected the reference to “Section V, Conditions 21.b and c” to “Section V, Conditions 22.b and c”.
- Removed Section II, Condition 2.1 for the Reg 6, Part B particulate matter standard as this applies to the boilers, which are no longer in the permit.
- Removed the recordkeeping requirements from 40 CFR Part 60 Subpart Dc § 60.48c(i) from the shield since these apply to the boilers, which are no longer in the permit.

- The permit shield for streamlined conditions (Section 3) was revised to address changes to NSPS GG (final revisions published in the federal register on July 8, 2004). To that end, the following revisions were made:
  - Removed the second line (§ 60.334(a) continuous monitoring system to measure and record fuel consumption rate and ratio of water to fuel), the NSPS allows the use of a NO_X CEMS in lieu of monitoring the water to fuel ration. In addition, the NO_X CEMS can meet the provisions of 40 CFR Part 75; therefore, no streamlining is required.
  - In the fifth line, second column of the table, the citation for § 60.334(b) was replaced with § 60.334(h)(3) and the references to §§ 60.335(d) & (e) were removed. The description in the brackets was changed to indicate the requirement is to monitor the sulfur content of the fuel.
  - In the sixth line, second column of the table, the citation for § 60.334(c)(1) was replaced with § 60.334(j)(1)(iii). The description in the brackets was changed to indicate the requirement is NO_X excess emission reporting.
  - The seventh line was removed. Excess emission reporting is only required if a source is required to monitor the sulfur content of the fuel. Sources using natural gas as fuel are not required to monitor the sulfur content of the fuel.

Section V – General Conditions

- Removed the statement in Condition 3.g (affirmative defense provisions) addressing EPA approval and state-only applicability. The EPA has approved the affirmative defense provisions, with one exception and the exception, which is state-only enforceable is identified in Section I, Condition 1.4.

- The upset requirements in the Common Provisions Regulation (general condition 3.d) were revised December 15, 2006 (effective March 7, 2007) and the revisions were included in the permit. Note that these provisions are state-only enforceable until approved by EPA into Colorado’s state implementation plan (SIP).

- Replaced the reference to “upset” in Condition 5 (emergency provisions) and 21 (prompt deviation reporting) with “malfunction”.

- General Condition No. 21 (prompt deviation reporting) was revised to include the definition of prompt in 40 CFR Part 71.

- Replaced the phrase “enhanced monitoring” with “compliance assurance monitoring” in General Condition No. 22.d.

Appendices

- Appendix B and C were replaced with latest version.

- The following changes were made to the tables in Appendices B and C.

    - The boilers were removed.
    - The serial numbers and size of the starter engines were included.
    - Included separate lines in the table for Brush 1, Brush 3 and the starter engines.
    - The “operating permit unit ID” for Brush 1 and Brush 3 was changed from “S001” and “S002” to “GT-1” and “GT-2”.

- EPA’s mailing address was revised (Appendix D). Removed the Acid Rain addresses in Appendix D, since annual certification is no longer required and submittal of quarterly reports/certifications is done electronically.

Total HAP Emissions (tons/yr) from Brush Cogeneration Facility - Based on Highest Emission Factor for Turbines*

Emission Unit	formaldehyde	acetaldehyde	toluene	benzene	acrolein	xylene	chloroform	hexane	Dichloro-benzene	nickel	cadmium	chromium	propylene	Total
BCP - Turbine	2.19	0.20	0.56	0.14	0.03	0.10								3.22
BCP - DB	0.02		9.76E-04	6.03E-04				0.52	3.44E-04	6.03E-04	3.16E-04	4.02E-04		0.54
BCP - engine	3.23E-04	2.10E-04	1.12E-04	2.56E-04	2.53E-05	7.81E-05							7.07E-04	1.71E-03
Brushco - Blrs	3.75E-03		1.70E-04	1.05E-04				0.09	6.00E-05	1.05E-04	5.50E-05	7.00E-05		0.09
BCP - Cool Twr							0.38							0.38
CPP - Turbines	6.73	0.14	0.42	0.49	0.02	0.07								7.87
Brushco - Blrs	0.01		3.91E-04	2.42E-04				0.21	1.38E-04	2.42E-04	1.27E-04	1.61E-04		0.22
CPP-Engines	3.23E-04	2.10E-04	1.12E-04	2.56E-04	2.53E-05	7.81E-05							7.07E-04	1.71E-03
CPP - Cool Twr							0.15							0.15
BIV - Turbines	4.95	0,.10	0.31	0.36	0.02	0.05								5.69
BIV - Cool Twr							0.43							0.43
Total	13.90	0.34	1.29	0.99	0.07	0.22	0.96	0.82	5.42E-04	9.50E-04	4.98E-04	6.33E-04	1.41E-03	18.60

*Turbine emission factors from AP-42, CATEF and EPA's 8/22/03 Memo - for all but BCP benzene and acrolein emissions, most conservative emissions are based on EPA Memo. BCP benzene and acrolein emissions based on CATEF.

The heating value of natural gas was presumed to be 1020 Btu/scf and the heating value of diesel was presumed to be 137,000 Btu/gal

Since the turbines have the highest HAP emissions, for CPP and BIV, HAP emissions are based on the turbine only. For BCP, because of the higher fuel limit, the turbine runs 8760 hrs/yr and the duct burner for the remainder.

HAP emissions from the BIV turbines are based on the annual hours of operation multiplied by the design heat rate.